Description

METHOD AND APPARATUS FOR SEISMIC FEATURE EXTRACTION

Technical field

[0001] The present invention relates generally to improvements in the field of seismography. In particular, the present invention provides a method and apparatus for processing seismic image data to more clearly reveal geologic features such as faults.

Background Art

[0002] Almost all geophysical exploration, and in particular hydrocardon exploration, includes the use of seismic methods. Seismic exploration generally begins with a seismic data acquisition in an area that has been identified as promising for hydrocarbon exploration. Seismic data acquisition surveys use acoustic sources (generally referred to as "shots") as a source of seimic waves. Those seismic waves propagate radially through the ground in accordance with the acoustic impedance (analogous to electrical impedance in electric circuit theory) of the geologic layer(s) through which the waves travel. For example, in , point S represents the location of such an acoustic source with respect to a vertical cross-section of ground showing two geologic layers or "strata" 100 and 102. Line 104 represents the direction of travel for a point on the radiating seismic wavefront generated by the source at S. Point R lies on the interface between two geologic layers having different acoustic impedances.

According to basic principles of physics, when a wavefront comes into contact with the interface between two media of different impedances (*i.e.,* an impedance "mismatch"), at least a portion of the wave energy is reflected back from the interface in the general direction of the source. Generally speaking, a portion of the wave energy will also be transmitted across the interface, although the direction of the transmitted wavefront may change. This change in direction is known as diffraction. Well-understood physical laws, such as Snell's law, govern the velocity and direction of these reflected and refracted waves. Thus, because the velocity and direction of incident and reflected or refracted waves can be determined mathematically, it is possible to identify the locations of acoustic impedance mismatches by measuring the amount of time it takes for a reflected/refracted wave to reach an observation point on the surface.

[0003] For example, in , an incident wavefront travelling in the direction of line 104 will reach the interface between layer 100 and layer 102 at point R, at which point the impedance mismatch between layer 100 and layer 102 causes a reflection of the wave to travel in the direction of line 106 to point D (the detection point) where the arrival time of the reflected wave can be measured. Since the velocity and direction of travel of the incident and reflected wave can be determined mathematically, the depth of point R, as measured from the surface can be determined from the arrival time of the reflected wave. This process is known as reflection seismography, and it

provides information about the locations, shapes, and material compositions of various geologic features. Knowledge of these features may be used for locating hydrocarbons or other mineral resources, as well as for other uses, such as determining the geologic structure of a particular site for civil engineering purposes, for example. Another application for this general type of technology is in the medical field, where ultrasonic acoustic waves are used in a similar fashion to perform medical imaging (*e.g.*, sonograms).

[0004] Returning now to the problem of geophysical exploration, however, it is customary to employ multiple seismic detectors at different points will be used in conjunction with a single acoustic source, to allow seismic data to be obtained over a broad area. Different types of acoustic sources are used in different arrangements, depending on the environment in question. Typically in onshore areas, "Vibroseis" acoustic sources are used to transmit seismic waves on the subsurface, which are transmitted and reflected off several subterranean layers, and eventually a portion of the originally transmitted energy is reflected back towards the earth's surface and received at detectors (receivers), which are spaced at predetermined spatial positions as to minimize the acquisition cost and increase the seismic data acquisition survey resolution. (Vibroseis was formerly a registered trademark of Conoco, Inc., but is now recognized as a generic term in the art). For offshore areas, the seismic vessel performing the

seismic data acquisition uses airguns or waterguns which generate a

significant pressure wave which propagates in the subsurface. The

reflected seismic energy travelling back from the subsurface towards the

ocean bottom is either received at receiver streamer cables towed by the

seismic vessel or by ocean-bottom receivers placed by oil and gas

companies.

[0005] Seismic survey data can also be categorized by the dimensionality of the

data. "Two-dimensional" seismic data is obtained by placing the detectors

in a single line. The information obtained in a two-dimensional survey

provides the same type of visual perspective as , where the two

dimensions are linear position along the line of detectors (horizontal) and

depth (vertical, plotted downward). One of ordinary skill in the art will

recognize that the depth coordinate is interchangeable with time, since the

arrival time of a reflected wave determines the depth of the reflector.

Mathematically speaking, two-dimensional seismic data is represented as

two dimensional scalar field, where the scalar value represents a

magnitude of the seismic signal received at a particular surface position at

a particular time.

[0006] "Three-dimensional" seismic data is obtained by arranging the detectors

over a two-dimensional area on the surface. Usually, the detectors are

arranged in some form of grid. A set of three-dimensional seismic data is

a three-dimensional scalar field that represents a magnitude of the seismic

signal received at a particular surface position at a particular time. During

seismic data acquisition, the data are typically recorded in digital media,

and their sheer volume, particularly in the case of a three-dimensional

survey, can easily exceed several terabytes (1×10^{12} bytes).

[0007] After the raw seismic data is obtained, it is then processed to extract

useful information, typically in a graphic format. A variety of seismic data

processing algorithms have been developed over the years. These

algorithms take into account the seismic source and receiver positions,

estimate the acoustic/elastic constants of the subsurface, and finally

"migrate" the data, meaning that they identify the proper locations of the

subsurface reflectors (*i.e.,* the geologic features that cause the reflection of

seismic waves).

[0008] At that point a three-dimensional volume is ready for a geoscience team to

start their seismic interpretation. Seismic interpretation can be broadly

subdivided into two components: *structural interpretation*, which

investigates the nature and geometry of the subsurface structures; and

stratigraphic interpretation, which investigates the subsurface stratigraphy.

A major component of structural interpretation is the identification, location,

and extraction of individual fault surfaces. Fault surfaces are very

important in hydrocarbon exploration because they are directly related to

hydrocarbon accumulation and to hydrocarbon flow paths. Extraction of

individual fault surfaces from seismic data is a largely qualitative

procedure and has thus been characterized by the need for careful human
data interpretation. Thus, geoscientists have long awaited automated
processes for geologic feature extraction.

[0009]   In recent years, there has been progress in visualizing stratigraphic and
structural discontinuties with the so-called coherence or variance methods,
which look at similarity or dissimilarity of a small number of neighboring
traces to determine these discontinuities. Some examples of these
coherence- and variance-based visualization techniques include US
5892732 (GERSZTENKORN) 06.04.1999 , US RE38229 E (MARFURT
ET AL.) 19.08.2003 , US 5563949 (BAHORICH ET AL.) 14.12.1994 US
5740036 (AHUJA ET AL.) 15.09.1995 , US 6151155 (DURFEE ET AL.)
29.07.1998 , and US 6138075 (YOST) 05.08.1998 . These existing
technologies, however, have a limited precision, and are incapable of
isolating fine details, such as fault surfaces or sedimentary layer interfaces
that may be only one pixel wide.

[0010]   Hence, there is a need in the art for an improved method of seismic data
processing that allows feature extraction to be performed at a higher level
of detail than is possible in existing methods. The present invention
provides a solution to this and other problems, and offers other
advantages over previous solutions.

Summary of the Invention

[0011]   A preferred embodiment of the present invention provides a method and

apparatus for extracting, separating, and labeling geologic features (such

as fault surfaces) in seismic data, which is of significant benefit in the art of

hydrocarbon exploration. The method includes steps of: a) reading a three

dimensional seismic data volume; b) computing the three-dimensional

orientation of the subsurface; c) subdividing the original volume into small

data volumes that are rotated at a predetermined set of dips and azimuths

related to those of the subsurface orientation; d) computing a 3-D edge

detection measure on the small volumes formed in step c; e) performing a

3-D contrast enhancement operation in each of the small volumes; f)

filtering the result of the contrast enhancement with selected 3-D filters at

the predetermined set of dips and azimuths; g) skeletonizing the results of

the filtering operation; h) separating the individual fault surfaces, and i)

labelling the individual fault surfaces for further interpretation and

exploration. The ultimate result obtained by a preferred embodiment of

the present invention provides a visual and semantic representation of a

set of well-defined, cleanly separated, one-pixel-thick labelled fault

surfaces, which is readily usable for seismic interpretation.

Brief Description of Drawings

[0012] The novel features believed characteristic of the invention are set forth in

the appended claims. The invention itself, however, as well as a preferred

mode of use, further objectives and advantages thereof, will best be

understood by reference to the following detailed description of an

illustrative embodiment when read in conjunction with the accompanying

drawings, wherein:

[0013]   Figure 1 is a diagram illustrating a process of reflection seismography;

[0014]   Figure 2 is a diagram depicting a marine seismographic survey vessel in

operation in accordance with a preferred embodiment of the present

invention;

[0015]   Figure 3 is a flowchart representation of an overall process of processing

seismic data in accordance with a preferred embodiment of the present

invention;

[0016]   Figure 4 and Figure 5 together make up a flowchart representation of a

process of skeletonizing features in edge-detected and filtered seismic

data in accordance with a preferred embodiment of the present invention;

[0017]   Figure 6 is a flowchart representation of an alternative process of

skeletonizing features in edge-detected and filter seismic data that may be

employed in a preferred embodiment of the present invention;

[0018]   Figure 7 is a diagram depicting the relationship between currently

examined value and its neighboring data values in the skeletonization

process described in and ;

[0019]   Figure 8 is a flowchart representation of a process of computing a local

orientation of skeletonized feature data in accordance with a preferred

embodiment of the present invention; and

[0020] Figure 9 is a flowchart representation of a process of identifying and

labeling distinct fault surfaces in accordance with a preferred embodiment

of the present invention.

Detailed Description of Preferred Embodiment(s)

[0021] Referring now to the drawings, FIG. 1 provides a schematic representation

of an oceanic seismic survey system 100 of the type used to obtain

seismic data which can be processed in accordance with preferred

embodiments of the present invention. The system 100 includes the use of

a seismic vessel 102 having an acoustic wave source 104 and a towed

array of spaced-apart receivers 106. For example, the towed array can

comprise a total of four to eight streamer cables which are towed in

parallel behind the vessel 102, with each cable having a large number

(such as 240) of the floatable receivers 106 which are serially attached to

the cable.

[0022] During operation, the vessel 102 transverses the surface of an ocean 108

in a regular pattern while periodically directing acoustic wave energy

(referred to as "shots") downwardly from the source 104. The wave energy

is reflected back to the receivers 106 at an ocean floor boundary 110, as

well as at subterranean boundaries (such as 112, 114). The signals

detected by the receivers 106 are converted to digital form and stored in

computerized data storage equipment (not shown) aboard the vessel 102.

It is common to subsequently transmit the resulting data sets to a land-

based processing center 116 using a suitable system, such as a satellite communication system 118.

[0023] The seismic data sets can be manipulated to produce three dimensional representations (images) of the resulting subterranean features, enabling decisions with regard to the desirability of further exploring a given location for oil and gas deposits. Because the seismic data are arranged in two spatial dimensions and one time dimension, as well as on a per shot basis, seismic data sets can quickly reach several tens of terabytes (10^{12} bytes) in size. Thus, to allow near real-time reporting of the seismic data sets to the processing center 116 (while the vessel 102 is still on location), the data are typically compressed and a compressed data set are transmitted via the satellite communication system 118. At this point it will be noted that present invention can be utilized in other environments as well, such as in an onshore exploration setting. Hence, the discussion of the environment of FIG. 1 has been provided merely for purposes of illustration, and is not limiting.

[0024]   A preferred embodiment of the present invention provides a method and apparatus for extracting, separating, and labeling geologic features (such as fault surfaces) in seismic data, which is of significant benefit in the art of hydrocarbon exploration. Turning now to the flowchart representation provided in FIG. 3, a method for seismic data processing and analysis in accordance with a preferred embodiment of the present invention is now

described. The method includes steps of: a) reading a three dimensional seismic data volume; b) computing the three-dimensional orientation of the subsurface (block 604); c) subdividing the original volume into small data volumes that are rotated at a predetermined set of dips and azimuths related to those of the subsurface orientation (block 606); d) computing a 3-D edge detection measure (normalized differential entropy or NDE) on the small volumes formed in step c (block 606); e) performing a 3-D contrast enhancement operation in each of the small volumes (block 608); f) filtering the result of the contrast enhancement with selected 3-D filters at the predetermined set of dips and azimuths to find the maximum directional local fault extraction (LFE) at each point (block 610); g) skeletonizing the results of the filtering operation (block 312); h) computing local orientation vectors for each point in the LFE volume and i) separating the individual fault surfaces and labelling the individual fault surfaces for further interpretation and exploration. The ultimate result obtained by a preferred embodiment of the present invention provides a visual and semantic representation of a set of well-defined, cleanly separated, one-pixel-thick labelled fault surfaces, which is readily usable for seismic interpretation.

[0025] In one embodiment of the invention, the steps of the invention are executed in accordance with instructions encoded in computer software by a data processing system that reads three-dimensional seismic volumes

and performs the fault surface extraction and labelling and generates a

volume with only the extracted individual fault surfaces. This resulting

volume can be readily overlaid on an existing seismic interpretation and

provides very high resolution detail of small seismic faults, such as

synthetic faults, which is virtually impossible to distinguish either manually

or with any other computational techniques. Numerous additional

advantages of the invention will become evident from the detailed

description, the claims, the drawings and the embodiments included.

[0026] The local orientation within the three-dimensional seismic volume is

computed first. The local orientation computation (with respect to a 2-D

seismic volume) involves perfoming the following computational steps

(which are also described in **RAO, A.R.**, et al. Computerized flow fields

analysis: Oriented texture fields. *IEEE Transactions on Pattern Analysis*

and Machine Intelligence. July 1992, vol.14, no.7, p.693-709.): first

smooth the 2-D volume with a local 2-D Gaussian filter; second compute

the gradient of the smoothed image; third compute the mean local

orientation over a small analysis volume; and finally compute a statistical

uncertainty measure called coherence. Assuming a volume with a 2-D

gradient value at the point (i,j) equal to $G_{i,j}$ $e^{i\phi_{jk}}$ (in Fourier coordinates)

then the local orientation estimate is given by the equation:

$$\phi_{mn} = \frac{1}{2}\tan^{-1}\left(\frac{\displaystyle\sum_{i=m-N/2}^{m+N/2}\sum_{j=n-N/2}^{n+N/2} G_{ij}{}^2 \sin 2\theta_{ij}}{\displaystyle\sum_{i=m-N/2}^{m+N/2}\sum_{j=n-N/2}^{n+N/2} G_{ij}{}^2 \cos 2\theta_{ij}}\right)$$

[0027] The statistical uncertainty of the local orientation estimate within a local

window W is given by the coherence measure:

$$\rho = \frac{G_{mn}\displaystyle\sum_{(i,j)\in W} \left\| G_{ij}\cos(\theta_{ij} - \theta_m) \right\|}{\displaystyle\sum_{(i,j)\in W} G_{ij}}$$

[0028] With respect to a three dimensional volume, the local orientation is

computed in the same way, with the difference that instead of one local

orientation there are actually two orientations, as, for example, we use dip

and azimuth for 3-D seismic data. Thus, the orientation is computed first

in a vertical plane to obtain a value for the dip, then next in a horizontal

plane to obtain a value for the azimuth. Thus, while the following

discussion involves calculating orientations of 2-D volumes, one of

ordinary skill in the art will recognize that the techniques described here

may be easily applied in the 3-D context by simply finding separate dip

and azimuth orientations through separate 2-D computations in vertical

and horizontal directions. Also, one of ordinary skill in the art will also

recognize that a high value of the statistical uncertainty measure implies

the presence of a fault surface. In existing coherence based methods,

such as is described in the aforementioned reference US RE38229 E

(MARFURT ET AL.) 19.08.2003 , this coherence measure is used directly

as an indicator of the presence of a fault surface. In a preferred

embodiment of the present invention, however, fault surfaces are identified

using edge detection and skeletonization techniques, instead, as will be

demonstrated below.

[0029] At this point, it is worth mentioning that there are also two other ways to

estimate the local orientation of the 3-D seismic volume. The first type of

estimate (after BIGUN, J., et al. Multidimensional orientation estimation

with applications to texture analysis and optical flow. *IEEE Transactions on

Pattern Analysis and Machine Intelligence.* August 1991, vol.13, no.8,

p.775-790.) is as follows: First convolve locally the 3-D volume gradient

with a local Gaussian function. Next, transform the seismic data so as to

map the data from a Cartesian coordinate system into the complex z-plane

(e.g., by mapping coordinates of the form (*x,y*) into complex numbers of

the form *x+iy*). Then, compute the local orientation as the argument of

the local convolution of the local volume gradient (∇f) with a 3-D Gaussian

filter (*m*) as follows

$$2\phi_0 = \arg((\nabla f)^2 * m)$$

[0030]   The statistical uncertainty measure of the local orientation is then given

by:

$$\rho = \frac{\left|(\nabla f)^2 * m\right|}{\left|\nabla f\right|^2 * m}$$

[0031] It turns out that both the local orientation estimate and its uncertainty

measure are by-products of the eigenvalues and eigenvectors of the

scatter matrix of the local spectrum, which is this case is implemented in

the first step outlined above. In fact, another expression for the local

orientation estimate is given in terms of the eigenvalues λ_0, λ_1, λ_2 by the

following expression

$$\rho = \frac{\lambda_1 - \lambda_0}{\lambda_0 + \lambda_1}.$$

[0032] The third way to estimate the local orientation of the 2-D seismic volume is

to perform a transform similar to a brushlet transform (MEYER, François,

et al. Brushlets: A Tool for Directional Image Analysis and Image

Compressions. *Applied and Computational Harmonic Analysis.* 1997,

vol.4, no.2, p.147-187.). In this transform, a 2-D Fourier transform is

applied to the whole 2-D seismic volume. The 2-D spectrum is then

subdivided smoothly as to generate consecutive polar regions

corresponding to a contiguous range of orientations. For instance

assuming an orientation range of 45 degrees, the 2-D spectrum is

subdivided in four polar regions. Neighboring polar regions are connected

through smooth bells similar to the ones employed in the design of local

trigonometric transforms (see, for example, COIFMAN, Ronald, et al.
Orthonormal Wave Packet Basis. *Yale University Technical Report Preprint.* 1989.). For each of these polar regions, by zeroing out the values outside the regions using appropriate smooth bells and performing an inverse 2-D fast Fourier transform (FFT), the component of the seismic data with local orientation in the range of orientations of the spectral polar region is determined. For example, if the polar region with polar angle of 0-45 degrees was inverted, then the component of the seismic data with local orientation between 0-45 degrees is determined.

[0033]   The next computational step in the disclosed invention involves subdividing the original three-dimensional seismic volume into a number of individual 3-D data analysis volumes of M x N x P dimension. One possible analysis volume is 41 values by 11 values by six values (41 x 11 x 6). The analysis volume is defined by the length along a major axis L_1, the length along a minor axis $2L_2+1$ (typically the horizontal axis), time duration of N samples, azimuth ϕ (rotation angle around the in-line axis), and tilt γ (tilt from the vertical axis).

[0034]   The analysis volume is broken into two subvolumes (for instance for a 41 x 11 x 6 analysis cube, each of the two subvolumes is 41 x 11 x 3 for a total of 1,353 values) which are rotated and tilted about a central analysis point $\lambda = (x, y, t)$. In the third dimension the time t or depth d are interchangeable. The samples within the respective subvolumes are

rearranged in a consistent manner into two column vectors $v_{1,\lambda}$ (γ,ϕ) and

$v_{2,l}$ (g,f) as can be seen in FIG. 4. The subvolumes seen in Fig.4 have

horizontal top and bottom surfaces. This is in particular preferrable when

the subsurface layers are horizontal or close to horizontal. However, we

also have the choice to have the horizontal top and bottom surfaces

parallel to the dominant local seismic orientation within the analysis cube

as seen in Fig.5. By rearranging the seismic data within the analysis cube

in such a way, the resulting column vectors can be directly used for edge

detection. In other words, the fault surface edges defined by a combination

of different position of the central analysis point I, the analysis cube size,

the rotation f and the tilt g are computed from the pairs of the

corresponding two column vectors. The computational method used to

compute the seismic edges is a normalized version of the Prewitt filter, as

it is explained in JAIN, Anil. Fundamentals of Digital Image Processing.

Englewood Cliffs, NJ: Prentice Hall, 1989. ISBN 0133361659. p.347, 351.

The original paper by Prewitt was published in Picture Processing and

Psychopictorics. Edited by LIPKIN Bernice, et al. New York: Academic

Press, 1970. ISBN 0124515509. The computations done by this

normalized version of the Prewitt filter are designed to capture the edges

and breaks visible or invisible, generated by subterranean faults in the

seismic data.

[0035]   A measure referred to as normalized differential entropy (NDE), or

N₁(g,f) is computed as a normalized version of the Prewitt filter .

$$
\frac{\left\|\mathbf{v}_{1,\lambda}(\gamma,\phi)-\mathbf{v}_{2,\lambda}(\gamma,\phi)\right\|_{p}}{\left\|\mathbf{v}_{1,\lambda}(\gamma,\phi)\right\|_{p}+\left\|\mathbf{v}_{2,\lambda}(\gamma,\phi)\right\|_{p}} .
$$

[0036]   where $N_l(g,f)$ is the normalized differential entropy. It is very interesting to

observe several things about the 3-D edge detection measure quantified

by the normalized differential entropy. First, if the subsurface layers have

orientation mostly horizontal with no significant lateral elastic impedance

contrasts then we have a NDE measure which produces an excellent edge

detector and indicator of the fault surfaces and at the same time a very

poor indicator of the subsurface layer interfaces. Second, even when the

dominant layer orientation is not horizontal by using top and bottom

analysis cube surfaces parallel to the dominant local 3-D seismic

orientation, we still obtain a very good 3-D edge detector and indicator of

the fault surfaces and at the same time a very poor indicator of the

subsurface layer interfaces. Third, the data structure employed for the

NDE and its 3-D edge detection computational architecture is completely

different than the data structures and the computational setup in the 3-D

seismic coherence and variance methods (US 5930730 (MARFURT ET

AL.) 27.07.1999 , US 5563949 (BAHORICH ET AL.) 14.12.1994 US

5740036 (AHUJA ET AL.) 15.09.1995 , US 5892732 (GERSZTENKORN)

06.04.1999 , US 5892732 (GERSZTENKORN) 06.04.1999). Fourth, the

result of the NDE and the seismic coherence are completely different in

particular when the top and bottom analysis cube surfaces are parallel to

the dominant 3-D seismic data orientation. Fifth, even if the top and bottom

analysis cube surfaces are horizontal the results of the NDE and the

results of the seismic coherency cross-correlation and eigenstructure

methods are completely different as evident in FIG. 6 showing an original

migrated line, FIG. 7 showing its NDE result, FIG. 8 showing the seismic

coherency cross-correlation result and FIG. 9 showing the seismic

coherency eigenstructure result. Sixth, when the top and bottom analysis

cube surfaces are horizontal there is a very significant overlapping of the

analysis cubes for any dip and azimuth combination and further than that

there are a lot of common difference computations which are repeatable

as it is evidenced by equation (6). All of the possible differences for the

NDE computations are computed upfront for all the combinations of the dip

and azimuth used, which yields significant acceleration in the NDE

computations. We have found from practical experience that a set of 12

dips from –35 to 35 degrees with a 5 degree increment excluding the dips

of –5, 0, 5 degrees and 8 azimuths (0, 45, 90, 26, 67, 116, 156) for a 41 x

6 x 7 NDE analysis cube is sufficient. By using the upfront NDE local

difference computations for all the combinations of dip and azimuth we

obtain a computational speedup of about a factor of 20, which is extremely

important for efficient computation and extraction of the fault surfaces.

[0037]   The next step of the disclosed invention involves 3-D contrast

enhancement. Fault surfaces having azimuths and dips equal to the

azimuth and dips of the analysis volume are distinguished by higher NDE

values compared to the local average NDE values. This contrast

enhancement facilitates the analysis of regions that contain dipping layers

or are highly discontinuous.

[0038]   The contrast enhancement can be efficiently implemented using a

discrete "Mexican Hat" function:

$$f(n) = C(1 - n^2)e^{-n^2/2}$$

where C is a normalization constant such that the sum of all the absolute

values of the Mexican hat is 2. A finite length filter (-4.5 < n < 4.5) is used.

This contrast enhancement filter contains odd number of uniformly spaced

coefficients. Good contrast enhancement results are obtained when using

31 filter coefficients, but in general the selected filter length depends on

the size of the analysis cube and the "thickness" of the fault surfaces. The

filtered NDE by the Mexican hat function is computed as

[0039]

$$\overline{N}_\lambda(\gamma,\phi) = g_\lambda(\gamma,\phi) * N_\lambda(\gamma,\phi) = \sum_{\lambda'} g_{\lambda-\lambda'}(\gamma,\phi) N_{\lambda'}(\gamma,\phi)$$

(8)

[0040] where gl(g,f) is a rotated version of f, such that its main axis is

perpendicular to the slabs of the analysis cube. The contrast enhanced

NDE volume is provided by

$$\hat{N}_{\lambda}(\gamma,\phi) = \max\{\overline{N}_{\lambda}(\gamma,\phi),0\}$$

[0041] FIG. 10 shows the results of the contrast enhancement applied to the

stacked migrated line shown on FIG. 6.

[0042]   The third step of the Fault Mapping System utilizes 3-D directional

filtering, which extracts the portions of fault surfaces that are

approximately aligned with the analysis cube.

[0043]   The directional filter, denoted by $h_l(g+a,f)$, is a 3-D ellipsoid, tilted by

g + a with respect to the time axis, rotated by f with respect to the in-line

axis, and normalized by

[0044] $\Sigma_l h_l (g,f) = 1$. The interpreter selects the filter dimensions, which control

the minimal dimensions of the detected subsurfaces. The maximum value

of a is determined by the increment D_g ($|a| < D_g / 2$). The implementation

uses a 3-D pencil-like shaped Hanning window. A possible set of

dimension values for this 3-D pencil-like window are 61 samples at its

major axis and 3 samples at its minor axes. A possible value for the dip

increment is $D_g = 5^0$, and a possible value for the relative tilt of the

directional filter a is restricted to $\{-2^0, 2^0\}$. A smaller dip increment could be

used and the relative tilt could be discarded; however, the above

formulation has been found to be computationally more efficient.

Directional filtering of the contrast enhanced NDE yields:

$$C_\lambda(\gamma + \alpha, \phi) = \sum_{\lambda'} h_{\lambda-\lambda'}(\gamma + \alpha, \phi) \hat{N}_{\lambda'}(\gamma, \phi)$$

(10)

[0045] The resulting coefficients from the application of equation (5) are

thresholded by d (0 < d < 1),

[0046]

$$\tilde{C}_\lambda(\gamma + \alpha, \phi) = \begin{cases} C_\lambda(\gamma + \alpha, \phi), \text{ if } C_\lambda(\gamma + \alpha, \phi) \geq \delta \\ 0, \qquad\qquad\qquad \text{otherwise} \end{cases}$$

(11)

[0047] and then filtered back to produce the directional LFE (Local Fault

Extraction) values, determined by:

[0048]

$$L_\lambda(\gamma, \phi) = \sum_{\lambda', \alpha} h_\lambda(\gamma + \alpha, \phi) \tilde{C}_{\lambda'}(\gamma + \alpha, \phi)$$

(12)

[0049] The directional LFE volumes contain significant portions of fault surfaces,

characterized by roughly the same dip and azimuth orientations as those

of the analysis cube.

[0050]   The fourth step of the Fault Mapping System involves keeping at

each point the maximum directional LFE value, over the tested set of dips

and azimuths. Specifically, the LFE attribute at the analysis point I is

obtained by:

[0051]

$$L_\lambda = \max\{L_\lambda(\gamma,\phi)\}$$

(13)

[0052]   The LFE volume gathers and connects the significant portions of

fault into smooth large fault surfaces as demonstrated in FIG. 11 which is

the result of the 3-D filtering operation on the original stacked line of FIG.

5.

[0053]   The next computational step involves a skeletonization step, which is

very important in both "filtering out" very small faults or fault-like features

and for separating the different fault surfaces. Skeletonization algorithms

have been in use in image processing for a significant time. This invention

discloses a skeletonization algorithm for 3-D data which is particularly

designed for the results of the filtering step outlined above. The

skeletonization algorithm disclosed performs the following computations

on each horizontal slice of the results of the filtering step previously

disclosed:

1. Using a data dependent threshold value we generate a binary volume.

    We use a 3 x 3 square to decide if the center point of the square P1

    should be kept or deleted. Within the 3 x 3 square, we denote N(P1)

    the number of non-zero neighbors of P1, T(P1) the number of 0-1

    transitions in the ordered sequence P2->P3->P4->P5->P6->P7->P8-

>P9->P2; then we classify and flag the point P1 as type-I point to be

deleted if:

2. $2 <= N(P1) <= 6$

3. $T(P1) = 1$

4. P4=0 or P6=0; or P2=0 and P8=0

5. Delete all type I border points

6. Flag the type II border points. In a similar manner as previously, a

point P1 is defined as a type II point if the following conditions are

satisfied:

7. $2 <= N(P1) <= 6$

8. $T(P1) = 1$

9. P4=0 or P6=0 or (P2=0 and P8=0)

10. Delete the flagged type II points.

[0054] Iterate through border points to be deleted until there are no more border

points to be deleted.

[0055] The algorithm for "fault separation, skeletonization and labeling" is as

follows:

[0056]

1. Binarize and skeletonize the 3D data:

a. For each horizontal slice 't', a 2D binarization and skeletonization is

performed using the "adaptive image binarization" algorithm (described

at the end of the document).

[0057]   b. For each vertical slice 'x' perform 2D skeletonization, and stretch

the skeletons (as described in the "adaptive image binarization" algorithm)

[0058] c. Repeat Step b for vertical slice 'y', horizontal slice 't', vertical slice 'x',

and so on, until there is no change in the result, or reached to a pre-

specified limit of iterations. Each iteration further stretches the skeletons,

so the fault surfaces become larger.

1. Remove small skeletons (2.5D):

a. For each vertical slice 'y' (ToX plane), remove objects whose size is

below a certain threshold.

b. Using the newly produced data, repeat step 2(a) of the algorithm for

each vertical slice 'x' (ToY plane) and again for each horizontal slice 't'

(XoY plane).

2. Label the 3D data:

a. For each separate azimuth, extract the data associated with that

azimuth and concatenate the extracted data along the fourth

dimension, ordered according to the azimuth value, thus producing a

4D data that contains the azimuth information as well. Label the newly

produced 4D data and re-create a 3D labeled data by taking the

maximum along the fourth dimension. This will create a labeled version

of the 3D data, such that objects are distinguished by their azimuths as

well, and therefore differently labeled if their azimuths are not close

one to another.

b. Identify objects whose size is above a certain threshold, remove all

other objects and re-label the remaining objects in an ascending order

(if more than 255 objects have been identified, keep only the largest

255 objects).

[0059] The algorithm for "adaptive image binarization" is as follows:

1. Define two thresholds - low and high.

    The high threshold should be defined such that low intensity objects

    will be removed by the high threshold binarization and yet objects that

    are supposed to be kept in the image will not be completely erased by

    the high threshold binarization.

    The low threshold should be defined such that connectivity between

    two close objects will be gained and yet no unnecessary pixels will be

    marked as '1'.

2. Binarize the original image using the high threshold (threshold

    operation only).

3. Skeletonize the binary image.

4. For each pixel in the skeletonized image that is marked as '1' and has

    no neighbors marked as '1' or has only one neighbor marked as '1'

    (edge points) do the following:

    a. For a pixel that has no neighbors marked as '1':

    Find the pixel with the maximum value among the 8-connected

neighborhood of the corresponding pixel in the original image.

For a pixel that has only one neighbor marked as '1':

Find the pixel with the maximum value among the pixels in the original

image that belong to the 8-connected neighborhood of the pixel and

are "not too close" to the neighbor pixel marked as '1'. The locations of

the pixels that are "not too close" to the neighbor pixel marked as '1'

are shown in the following figures (the left figure refers to the possibility

that the neighbor marked as '1' belongs to the

4-connected neighborhood and the right figure refers to the other

possibility):

[0060]

Table 1

Neighb or Marke d as '1'		
	Center Pixel	X
	X	X

[0061]

Table 2

Neighbor Marked as '1'		
	Center Pixel	X
	X	X

[0062]   b. If this maximum value is above the low threshold, mark the corresponding pixel

in the skeletonized image as '1'.

Otherwise try to find such a pixel (i.e., one that is above the low threshold) in the 5x5 neighborhood in a similar manner. If such a pixel exists, mark the corresponding pixel in the skeletonized image as '1' and also mark the appropriate pixel in the 3x3 neighborhood so connectivity will be retained.

c. If the newly marked pixel (the outer pixel in the case of 5x5 neighborhood) has only one neighbor marked as '1', go to step 4(a) in the algorithm for the newly marked pixel.

[0063]   <u>Remark:</u>

- The skeletonized image is updated as necessary at the various steps of the algorithm, and every step in the algorithm uses the previously updated skeletonized image.

[0064] Implementation Details:

- The function that implements steps 4(a) through 4(c) in the algorithm can be implemented as a recursive function (and is recursively called as necessary in step 4(c) of the algorithm).

[0065] It is important to note that while the present invention has been described in the context of a fully functioning data processing system, those of ordinary skill in the art will appreciate that the processes of the present invention are capable of being distributed in the form of a computer readable medium of instructions or other functional descriptive material and in a variety of other forms and that the present invention is equally applicable regardless of the particular type of signal bearing media actually used to carry out the distribution. Examples of computer readable media include recordable-type media, such as a floppy disk, a hard disk drive, a RAM, CD-ROMs, DVD-ROMs, and transmission-type media, such as digital and analog communications links, wired or wireless communications links using transmission forms, such as, for example, radio frequency and light wave transmissions. The computer readable media may take the form of coded formats that are decoded for actual use in a particular data processing system. Functional descriptive material is

information that imparts functionality to a machine. Functional descriptive material includes, but is not limited to, computer programs, instructions, rules, facts, definitions of computable functions, objects, and data structures.

[0066]   The description of the present invention has been presented for purposes of illustration and description, and is not intended to be exhaustive or limited to the invention in the form disclosed. Many modifications and variations will be apparent to those of ordinary skill in the art. The embodiment was chosen and described in order to best explain the principles of the invention, the practical application, and to enable others of ordinary skill in the art to understand the invention for various embodiments with various modifications as are suited to the particular use contemplated.